Evaluating Locational Marginal Pricing (LMP) in the UK: RWE Response to Ofgem Initial Call for Evidence
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About RWE

RWE is one of the UK's largest power producers and renewable energy generators, accounting for around 15% of all electricity generated in the UK, with a diverse operational portfolio of onshore wind, offshore wind, hydro, biomass and gas, amounting to over 9.3GW – enough to power over 10 million UK homes. For an illustration of our footprint, please see our UK infographic here.

In addition to its growing renewables portfolio, currently totally 2.1GW, RWE operates around 7GW of modern and efficient gas-fired capacity in the UK, making us one of the largest providers of firm flexible generation, which is crucial for security of supply. Overall, and including its committed investments in projects already under construction, RWE expects to invest up to £15billion in new green technologies and infrastructure in the UK by 2030.

Submission Overview

The case for Locational Marginal Pricing (LMP) relies on the benefits of more efficient dispatch and better longer-term locational decisions outweighing the associated costs. This requires a detailed and thorough understanding of the source of the benefits and costs and *crucially* the separate identification of any net benefits over and above the transfer of rents from generators to consumers. While modelling will provide some insights here, LMP raises multiple economic, commercial and regulatory challenges that must be addressed for it to work and specifically to ensure that the risks presented by more "efficient" nodal prices in the short-term translate into the more efficient delivery of the transmission, generation and consumption investment required to deliver net zero in the longer-term. While many of the risks of LMP can be mitigated by the issuance of long-term transmission rights, these bring other commercial and regulatory challenges. There is unlikely to be a "perfect" trade off here and it will be a difficult balancing act to allocate the risks of transmission availability and the costs of congestion optimally between generator, consumer and ESO. The delivery of LMP therefore requires a much broader "enhanced" model of the market and regulatory framework than modelling of the dispatch benefits can deliver alone.

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1. Evaluating the Opportunities Associated with More Granular Locational Pricing

The case for Locational Marginal Pricing (LMP) relies on the benefits of more efficient dispatch and better longer-term locational decisions outweighing the associated costs. This will require a detailed and thorough understanding of the source of the benefits and costs and *crucially* the separate identification of any net benefit from the myriad transfers between individual generators and consumers. The questions to be addressed can be broadly broken down into short-term dispatch efficiency, long-term efficiency of location decisions and the separate identification of the net benefits from the impact of transfers between generators and consumers.

Will LMP increase efficiency of dispatch in the short-term?

LMP *can only* deliver more efficient dispatch if it *changes* the pattern of generation and demand in a way which:

(a) reduces the total costs of production (wholesale and balancing); and/or
(b) diverts demand to more valuable uses; and/or
(c) allows more demand to be fulfilled economically (marginal value > marginal cost) or removes demand that was not economic to meet.

Demonstrating this will require a range of qualitative and quantitative questions to be addressed. In addition to any quantitative modelling results, it will be important to have a more intuitive understanding of *why* dispatch is changing to address the following questions.

- Does LMP *change* the pattern of generation and demand compared to current patterns of despatch during each day and from season to season? How does LMP drive changes in dispatch and why do the current balancing arrangements fail to capture those changes?
- Which generators and consumers are changing their production or consumption patterns?
- How does LMP reach *additional* generation and demand resources that cannot respond either explicitly via existing balancing arrangement and/or implicitly in response to half-hourly prices?
- Are the resulting price changes sufficient to change generator or consumer behaviour?
- Are the changes the sole result of LMP and/or could other design options or resources deliver similar dispatch responses without LMP (e.g., central despatch, new balancing arrangements, shorter settlement periods, improved ESO Control Room optimisation tools, local markets/services, SMART tariffs, MWh transmission tariffs).
- How does LMP interact with the optimal purchase of other system services on the transmission and distribution systems (e.g., capacity, reserve, reactive power, stability, frequency response)? Does the procurement of other services enhance or override the LMP price signals?
- How will the temporal optimisation of resources be organised under LMP? What gate closure will apply and will unit commitment be by central or self-dispatch? How will the balancing arrangements change to accommodate LMP?

- How will the benefits or costs of changes to the market and balancing timescales – e.g. the costs of returning to day-ahead central dispatch and an increase in balancing actions within day - be separated out from the benefits case for LMP?[1]

Any short-run efficiency gains also need to be set against the implementation costs and ongoing running costs of LMP which would include

- Cost of modelling, analysis during the detailed assessment phase.
- Cost of implementing new LMP models, data and communications at ESO and market participants.
- Costs to revise/replace BSC, CUSC, TNUOS etc and introduce new governance and change management processes.
- Ongoing cost of governance framework, staffing and systems costs to ESO and all market participants.
- Financial cost of credit support to ESO to underwrite long-term financial transmission rights.
- Cost of redesigning and implementing revised methods of low-carbon support and the capacity mechanism.

Will LMP increase efficiency of long-term investment decisions to deliver net zero?

The question of whether LMP of electricity will optimise long-term investment decisions across the power is complex. It would appear unlikely that LMP alone would prove sufficient to drive investments given that EMR has established the need for parallel low-carbon support and capacity markets to underwrite investment against the single energy price market. However, we need not only need to understand how LMP will work with these parallel instruments, we also need to recognise that – even in theory - LMP does not provide unique long-term signals for location or transmission investment.

While LMP has the potential to inform decisions on the future location of generation and demand resources, several inherent features of transmission networks mean that it is impossible to translate efficient short-term marginal cost signals into efficient long-run marginal cost signals on where generators and load should site and where transmission should be built. There features include:

- **Economies of scale in transmission** mean that future short-run marginal cost signals will be insufficient to recover the long-run costs of investment even for economic investments.
- **Network externalities** mean that an incremental investment in generation, load or transmission at one point on the network will affect the locational marginal price at every other point on the network.

These market failures are, in turn, at the heart of a natural monopoly in electricity system operation (ESO) and the prohibition on "merchant" investment in transmission. Only a regulated ESO can take decisions to build in advance of need to make the most of future economies of scale; to prevent individuals from building (or preventing build) to protect their

[1] We would note here that the benefits case for the New Electricity Trading Arrangements in 1999 relied heavily on the move away from centralised day-ahead dispatch to self-dispatch with a later gate closure. The case for moving **away** from day-ahead central dispatch is arguably even greater in the world dominated by renewables and with new sources of flexibility on the demand side.

assets at the expense of others; and to make the correct trade-offs between siting decisions on generation and load and transmission build and reinforcements.

The natural ESO monopoly must in turn be properly regulated to overcome the natural monopolist's default of under-delivering to increase prices and to maximise profits. In this context, the costs of congestion move from being an ESO "cost centre" under the current market design, to become a primary "profit centre" to the ESO under LMP. The "efficiency of long-term investment" therefore relies on the efficient regulation of the ESO and the effective use of the congestion rents and the wider framework for transmission rights and revenue recovery. Ofgem will need to work with the FSO to provide a strong framework of regulatory incentives to ensure that the system is planned – and built – to deliver net zero optimally; LMP alone cannot and will not achieve this.

The current Wider TNUoS Charge arrangements are designed to incentivise generation assets to make locational decisions that minimise transmission system use for actual active power during periods of high gross demand. It will be important to consider whether these arrangements have achieved this aim or not and if not why not? We think that there is a strong argument that this mechanism has been successful if we consider that current BSUoS costs are largely associated with reactive power, rate of change of frequency and operational reserve constraints and if thermal constraints do not tend to occur at periods of high gross demand.

It has not yet been proposed how non-thermal constraints will be managed under LMP, and whether they will be co-optimised with active power needs, and whether LMP will attempt to reduce these costs. Of course, it would be wrong to assume that modelling an active power wholesale market would eliminate BSUoS costs associated with non-thermal constraints. It may be very difficult to estimate what BSUoS costs remain for a thermally constrained nodal wholesale market, especially given that ancillary services system needs, replacement energy and imbalance are currently co-optimised in similar timescales. For example, if there are thermal power constraints but the system is already expected to be long, replacement energy may not need to be instructed to the extent of the imbalance volume. Should thermal power constraints be addressed in different timescales to imbalance, replacement energy will always need to be instructed where constraints exist, but will frequently need to be unwound again if the system is long. This effect is likely to reduce market efficiency. Ancillary Services system needs and balancing activity in short-term timescales is very complex, and so far there has been no attempt to model either of these activities as far as we are aware.

Beyond the question of regulatory incentives to invest in transmission and to site generation and load is the question of to what extent exogenous factors constrain, limit or drive investment such that we're effectively LMP "price takers" rather than "price makers". To address this, we need to understand:

- Whether variation in LMPs over time translate into longer-term "structural" variation in locational prices that would be sufficient to influence major investments.
- Do the resulting price differences result in *different, more efficient* location choices for offshore wind, onshore wind, solar, H2 etc or are other constraints (i.e. lease locations, wind resource, planning framework, etc) more important on location choices?
- Are the LMP price differentials sufficient to overcome other locational cost drivers and associated locational risks (see section 2 below).
- What locational constraints do new generation sources and major loads (e.g., electrolysers) face in terms of the availability/use of resources and ability to site? For example, to what extent does the availability of offshore leases limit ability to move

offshore wind to other locations? Is the development of onshore wind limited to Scotland given planning constraints in England and Wales? Can electrolysers/CCUS plants be built anywhere, or do they need to be close to industrial H2 load and/or carbon stores?

- Would transmission reinforcement be cheaper than the opportunity cost of relocating generation and load to alleviate the resulting constraints?
- How much residual cost will be saved as a result of more efficient locational decisions after accounting for transmission investments (that could have/should have been) made in the non-LMP world?
- How will LMP interact with parallel markets for low-carbon support and firm capacity? Will LMP complement these parallel markets, or will locational decisions be overridden/diluted by parallel support schemes?

Even if we can address all these challenges to design the optimal regulatory framework to translate short-term prices into meaningful, efficient changes in the pattern of investment in generation load and transmission, we need to recognise that the electricity system needs to be jointly optimised with the networks associated with all other energy vectors required to deliver net zero (gas, hydrogen, ammonia, carbon capture, transport and storage etc). LMP is far from a panacea to this unique regulatory challenge.

Separating the benefits of LMP from transfers to consumers

Although initial modelling suggests that LMP benefits customers, we need to be very cautious about concluding that this justifies the introduction of LMP for several reasons:

- **LMP does not unambiguously reduce cost to consumers**; some consumers will pay more, and some will pay less. (Also see the risk that this poses in section 2 below.)
- **The primary source of the "benefit" to consumers is a transfer from generators and should not be included in the CBA.** The primary source of the "benefit" to consumers is not a benefit at all, but the inevitable conclusion of changing the point of sale in the electricity market and thereby removing constrained off payments to generators. This is a straight transfer of rent from generators to consumers. It is not a societal benefit, and it should be excluded from the cost-benefit analysis.
- **The dispatch "benefit" will be offset by increased costs elsewhere.** As discussed above, there is no guarantee that the short-run signals deliver more efficient transmission investment and more efficient locational decisions from generation and load. Removing constrained off payments from marginal generators at the dispatch stage will also require higher-payments in parallel low-carbon support or capacity markets to meet the cost of new entry. It may also increase risks and the cost of capital (see section 2) more widely to the extent that the transfer of congestion rents from generators to consumers **increases the total cost to consumers.**

It will therefore be essential to separate out the distributional impacts of LMP from the underlying costs and benefits across the piece and not just consider the rent transfer at the dispatch stage. Any cost-benefit assessment should also be consistent with the proposed method of implementation. Here, we are particularly concerned by the prospect of a decision being made to proceed with LMP predicated on efficiency gains stemming from more accurate pricing and engagement on the demand side only for a later decision to be taken to address the uncomfortable distributional consequences by only applying LMP to generators and continuing to have a national price on the consumer side.

2. Key Implementation Challenges, Risks and Mitigations

The previous section has illustrated that the "theoretical" case for LMP opportunities must both separate out rent transfers and ensure that any remaining short-term dispatch benefits translate into longer term gains from better siting of generation and load and more efficient transmission investments. There are several additional, practical challenges to achieving these benefits that must be addressed and mitigated as part of an "enhanced" LMP model if LMP is going to prove beneficial.

Impact on low-carbon support and capacity markets

The CFD regime for low carbon support and UK capacity market are both predicated on an energy market in its current form. Both mechanisms will be essential to deliver net zero and yet would need to be fundamentally redesigned to deal with the introduction of LMP in the future. This presents the twin challenge of determining both the future design of these instruments to be compatible with LMP, but also how existing long-term CFDs and capacity agreements would be accommodated or changed to transition into the new market design. Consideration also needs to be given to the risk that the capacity instruments undermine or negate the locational signals stemming from LMP

The transition to a net zero economy and a zero-carbon electricity system requires massive investment over the coming years. A reform as fundamental as LMP – and the required reforms to low-carbon support and the capacity market - presents a serious risk of a hiatus in investment given the uncertainty to investors during an assessment and implementation period that could run up to the end of the decade. We also can't ignore the fact that improved network planning and development could have helped to avoid the current high constraint costs and that while these costs are forecast to rise initially, they will fall back as transmission is reinforced later in the decade. Ofgem and Government therefore need to assess carefully whether the benefits case is sufficiently robust and whether the risks to delivering net zero are sufficiently great to justify such a fundamental market reform at the current time.

LMP will increase the Cost of Capital

Generators and customers can currently hedge their sales and purchases via a national electricity market in Great Britain. LMP will fragment this market into many individual market nodes. Hedging might concentrate on one or more basic reference nodes (e.g., a central or fixed location) or another form of benchmark (e.g., the price at the "swing" or unconstrained hub). However, market participants will then face the risk of the "basis" or difference in prices between the hub price and their locational marginal price.

Over the life of a project, this basis risk can be significant and can ultimately lead to the stranding of assets in particular locations. Investors will consequently seek a premium for exposure to the locational basis risk. In Texas, our experience is that the premium required for a "station gate" contract over a "system contract" is in the order of 100-150 basis points.

Further increases in the cost of capital would stem from the redistribution of congestion costs from consumers to generators. The guarantee of firm transmission to generators has been a feature of the UK market arrangements since Vesting of the industry in 1989. Firm transmission was seen as being required to insure generators against the risk of their asset being stranded if transmission is not available. This seemed reasonable given that generators have no control over that risk. The principle has been further reinforced since with the decision to “Connect and Manage” rather than offer different degrees of firmness to new connections. The removal of “constrained off” payments to generators can therefore reasonably be seen as both abrogating rights of existing generators and introducing a new uncontrollable risk of transmission availability to generators.

The risk of transmission withdrawal and transmission basis risk can both be hedged with firm transmission rights. We would see the distribution and sale of long-term (to match investment horizons) firm transmission rights as an essential component of any LMP proposal. As the recipient of the congestion rents in the first instance, it is essential that the ESO is the counterpart to those rights. While market participants are collectively “short” congestion, the ESO is the only party that is “long” congestion; earning more as congestion rises. Transmission rights therefore allow the ESO to stabilise their congestion revenues. The issue of firm transmission rights also gives the ESO an incentive to maintain the volumes of transmission sold to avoid being “short” transmission. This is an essential component of the wider regulatory “wrapper” required to ensure that LMP delivers.

Long-term incentives require long-term transmission rights

LMP will only influence location decisions sufficiently in the long-term, if investors are able to “lock in” that benefit to avoid the risk of investments being “stranded” by subsequent location decisions and/or grid investments. This would require the ESO to issue long-term firm transmission rights.

While existing LMP schemes feature firm transmission rights, none have anything beyond three years. This is clearly insufficient to hedge the life of an asset and there is clearly a trade-off here between the length of the rights and the increased cost of financing the transition to net zero.

Are the distributional consequences acceptable politically?

Many of the benefits of LMP stem from more accurate pricing of electricity on the demand side. This will be particularly important as we transition to net zero for the location of significant loads from storage sites, data centres and electrolysers. The corollary of this may be significant variation in the price paid by consumers in different parts of the country. There is a risk that these variations are not deemed to be politically acceptable at the point of implementation and/or that implementation – and the realisation of the benefits – is compromised by the retention of average prices on the consumption side with LMP only on generators. Ofgem and Government therefore need to be reasonably sure from the outset that they are willing to push through the required changes in prices. If this is not the case, then any economic analysis needs to also consider a case where demand signals are not included in the LMP outcome.

We’d note here that there are ways to both mitigate the *initial* distributional consequences while retaining forward looking incentives for LMP. This would involve the granting of fixed volume firm transmission rights with the intent of "grandfathering" the current distribution of consumer and generator rents. While this would solve the problem, it would make the current cross-subsidies from "good" to "bad" locations perfectly transparent which may bring its own problems (e.g., the perception of the "compensation" being paid by Scottish consumers to London consumers).

Credit, collateral and competition

Long-term transmission rights (and potentially obligations) are the solution to many of the risks posed by LMP. They will be essential to mitigate the transmission pricing and availability risks; the means for locking in the benefits of generator and load location decisions; and the means for ensuring that the ESO can manage their exposure to congestion costs while maintaining incentives to deliver efficient levels of transmission. They also provide a means to mitigate many of the distributional consequences of LMP.

Long-term rights, however, raise a range of issues themselves and primarily how the respective obligations of generators, consumers and the ESO can be collateralised over the long-time periods required. This raises questions both about the financial structure of the ESO and the degree to which long-term transmission risks should be borne best by generators, suppliers, the ESO and individual customers and whether some risks would or should be socialised.

Regulators have also traditionally been wary of issuing long-term rights and grandfathering rights because of concerns about limiting the scope for competition. This raises a further set of challenges in relation to whether LMP undermines the "dynamic" efficiency of the market by raising barriers to entry to potential competitors:

- What impact will LMP on competition in the generation and supply markets?
- What barriers does the additional complexity present to smaller new entrants into the markets?
- Can LMP prices be effectively hedged in forward markets? What impact will LMP have on buy-sell spreads and the costs of hedging?
- Does LMP facilitate the exercise of locational market power?

While it's possible therefore that "more creative retail business models might emerge", it's also true that LMP could stifle retail competition by preventing suppliers from effectively hedging their risks. There is significant evidence of this in Norway, where local producers face little competition at the local retail level because they enjoy a natural "hedge" on the zonal price whereas retailers without production in that area cannot hedge the basis risk between the local prices and the liquid NordPool spot and forward prices. Texas also has good experience of mass supplier bankruptcies stemming from extreme weather driving extreme LMP prices. As in the UK recently, this has raised questions about the retail business model and the extent to which hedging can be mandated/required.

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3. Modelling Zonal and Nodal Market Designs

The modelling should hopefully take us beyond the headline transfer of rents from generators to consumers to give us real insights into what behaviours are driving any underlying short-term and long-term benefits. The modelling should also give us a sense of the magnitude of the likely LMP price differences and the means by which they either deliver the benefits or the risks identified.

In terms of outputs. the modelling should hopefully demonstrate whether the likely price changes will be sufficient to change generator or consumer behaviour and how much LMP might *change* the pattern of generation and demand:

- Which generators and consumers are changing their production or consumption patterns?
- How much will LMP change energy prices during the day, from day to day and from season to season across the system?
- How much do prices change on average in each location?
- How will local prices change over time, and will they be stable/predictable?
- What are the potential extremes of very high or very low prices (c.f., ERCOT)?

This will give us insights into whether LMP is likely to drive underlying behaviour changes, whether other instruments (e.g., locational transmission tariffs) might effect similar change and an insight into the likely distributional consequences.

We would like to understand how temporal dispatch uncertainty would be modelled to avoid the benefits case being based on an unrealistic assumption of perfect foresight. Specifically, if LMP is accompanied by a return to day-ahead central dispatch – for example – how will the resulting increase in the cost of rebalancing and optimisation within day be treated?

A similar concern applies to the treatment of existing and future CFDs. LMP will create basis risk against existing benchmarks or require a change in reference prices and/or more optimisation actions in short-term markets. How will any increase in costs to compensate for the change and to manage the risks in short-term markets be factored into the benefits case. Similarly, how will any increase in the risk premia required to hedge increased basis risk in future CFDs be accounted for?

On the long-term questions, we need to understand how much difference LMP will make to total costs in a future "net zero" world where the markets for low carbon energy and firm capacity do more heavy lifting and where there are more periods of low and zero prices in the energy wholesale market. It's important that the modelling correctly captures the likely future options for generation, storage and consumption both in dispatch behaviour and location decisions. This requires transparent, realistic assumptions on siting constraints etc and clear scenarios on the location of significant loads (e.g., electrolysers etc).

More widely, modelling endogenous capacity development in Plexos is problematic and will need significant interpretation and justification. A key assumption is about network reinforcement; obviously if the network is sufficient the benefits on LMP will be negligible which begs the question of what will or won't be deemed sufficient and/or be approved under the future regulatory framework. Previous assumptions on network investment have looked quite conservative and we would like to better understand how capacity will develop with a more robust approach to network reinforcement and the associated cost trade-offs.

We would recommend that the modelling covers all four scenarios. Steady Progression is a very plausible scenario for the next 20 years and should not be discarded on the grounds that it does not hit net zero in 2050[2] especially given the CCC view that this is the earliest date for getting there. Similarly, "Leading the Way" is an extreme optimistic scenario, and its inclusion skews results toward a very improbable outcome.

We would expect to see the benefits discounted appropriately presumably by a similar discount rate to that used for network investment

Finally, we would be very wary of drawing conclusions about nodal pricing from zonal modelling and vice versa. Our experience of operating within nodal environments is that you can have occasionally extreme and counter-intuitive price excursions at individual nodes that deviate from the broad "zonal" or "regional" picture. We would expect the outcome of any nodal modelling to inform the choice of zones to model rather than relying on boundaries identified for other purposes or historically observed. The question we need to address is whether a zonal approach could or would approximate to a nodal system and how many zones might be required to capture the key price differentials. Any historic or observed approach therefore risks prejudging the very question it is designed to address. Using existing zones or boundaries may also identify zonal differences that would not appear or appear in different places with a nodal approach. The danger then is that an efficient zonal approach gets unduly discarded.

[2] As a result of further consideration, this represents a change from our response of 10 June 2022 on the modelling assumptions where we agreed with the exclusion of Steady Progression